INTEGRATED GEOSTATISTICAL SEISMIC INVERSION TO PREDICT A THIN SANDSTONE RESERVOIR UNDER FAN DELTA SEDIMENTARY ENVIRONMENT: A CASE STUDY IN THE JUNGGAR BASIN

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ABSTRACT

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Well drilling proved that the Permian's rough grained sandstone reservoir in the centre of Junggar basin was not fully controlled by structure. This type of reservoir is traditionally difficult to identify on conventional seismic data because of the lack of an effective workflow to detect lithology and fluid using real logs and seismic data. In this case study of PetroChina's Xinjiang oilfield, China we present an effective workflow for describing the spatial distribution of sandstone reservoirs and for the feasibility of fluid detection, explaining the reasons why the wells drilled within the higher area of the structure produce water while the other wells located within the lower area produce oil.

Forward models derived from petrophysics and rock physics defined the resolution of deterministic inversion, the AVO response of the real reservoir sequence, which inversion method and which elastic parameter were most sensitive to lithology and fluid changes under the real geological environment. In addition, they provide a benchmark for seismic data quality. Higher-resolution reservoir characterization of geostatistical inversion gave the sandstone spatial distribution, the reservoir discontinuity and the horizontal thickness. This integrated workflow guarantees that the final geological map is meaningful not only in terms of elastic parameters, but also in terms of geology, petrophysics, geophysics and engineering.

KEY WORDS: petrophysics, rock physics, forward modelling, geostatistical inversion.

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INTRODUCTION

The Permian's thin sandstone reservoir in the centre of the Junggar Basin is traditionally difficult to identify on conventional seismic data. Bed thicknesses vary rapidly between wells from 2 to 20 meters which may be beyond the typical seismic resolution. This calls for a wavelet tuning and seismic resolution test based on the real reservoir state. Subtle changes in seismic amplitudes can be due to different components within a fan delta environment such as porosity, water saturation, granularity, clay volume or even lithology changes. A rock-physics integrated AVA gather forward modelling makes it possible to quantify the effect of these changes on the seismic amplitude.

Petrophysical analysis and interpretation together with robust rock physics modelling of well logs suggests that the Permian's sandstones have a distinct elastic response that separates the reservoir sands, the tight sands, and the shale lithology. These cross-plot observations at well log resolution, may not be valid at seismic resolution, they need to be verified by seismic forward modelling. This makes it possible to establish a rock-physics interpretation cross-plot on elastic parameters which can be obtained from pre-stack inversion. The separation of rock properties observed in the cross-plots implied a seismic AVO effect and that shear wave information obtained from offset seismic data was essential to distinguish sandstones from shales and fluid types. Full-stack seismic had no such distinguishing power, but higher-resolution reservoir characterization of full-stack geostatistical inversion rather than geostatistical AVO inversion algorithms were promoted for their utility in the identification of thin porous sandstones because of the poor quality of the real gather dataset. Analyses using both deterministic (best single answer) and geostatistical (sets of possible answers) were completed. The latter had the added advantages of higher resolution and an estimation of uncertainties associated with the rock properties from which probabilities could be calculated. At the well locations, the geostatistical inversion predicted the thin sand on a blind well accurately. Away from the wells, the inversion reservoir spatial distribution clearly shows the sandstone's discontinuity and lithology boundary which match well production.

The objectives of this case study were to:

1. Build a roadmap of the integrated seismic reservoir characterization workflow for the fan delta geology environment.

2. Produce highly detailed 3D inversion results that can delineate the space distribution of thin sands, explaining why water is produced from the higher spot while oil is produced in the lower position of the study area.

3. Qualify the success of the integrated workflow as a predictor of reservoir, and verify its benefits in terms of efficiency, accuracy and drilling well risk reduction.

METHODOLOGY

The input data included a 100-square-kilometre 3D post stack seismic dataset and five wells, two of which contained dipole sonic logs (Fig. 1). In order to achieve the objectives, an integrated workflow of four main steps was created (Fig. 2).

Firstly, "seismic petrophysics" transforms resistivity, gamma ray and porosity tool measurements into reservoir properties such as lithology fraction, porosity, hydrocarbon saturation and permeability.

Secondly, the rock physics model was built to transform the petrophysical properties into sonic and density parameters and also to create the link between the elastic and petrophysical properties.

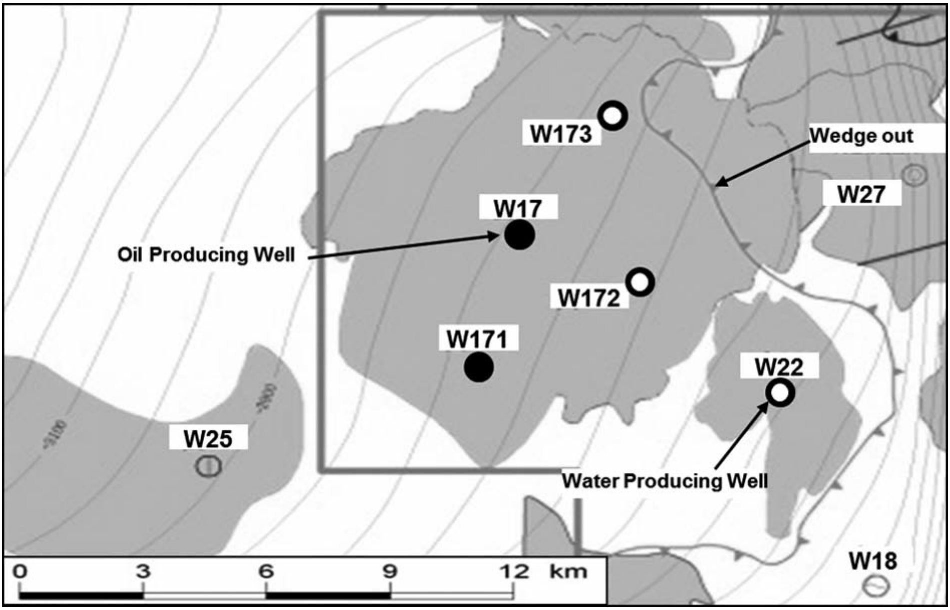

Fig. 1. Base map of area of interest. Five wells were used in the seismic inversion. The two wells plotted in solid black circles are commercial oil wells; the other three wells plotted in open circles on the higher structure were water-producing wells.

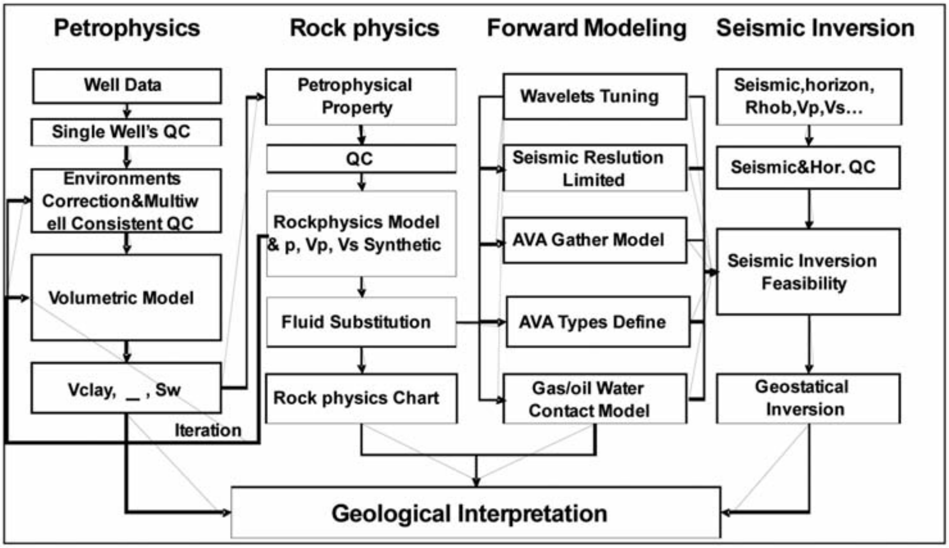

Fig. 2. Roadmap of the integrated seismic characterization workflow.

Thirdly, using rock physics models for fluid, porosity and shale volume substitutions, angle gathers were synthesized using the Zoeppritz equation. The reflectivity and seismic amplitude versus angles were extracted on the oil top. In this case study quantitative seismic inversion was more effective than qualitative AVO property analysis.

Finally, the Oil Water Contact was modelled to define which elastic parameter is most sensitive to lithology and fluid: P-impedance, S-impedance or Poisson's ratio which can be deduced from seismic inversion under certain geological conditions and real seismic data quality.

The AVA wedge model demonstrated that the resolution limitation of the deterministic inversion driven by the geological conditions and by the seismic data quality cannot meet the project requirements. Higher-resolution reservoir characterization of geostatistical inversion should be used instead, to give the connectivity of sand bodies within the target zone.

At each step of this iterative workflow, quality control is applied. Iterations may occur in steps such as the link from petrophysics to rock physics.

Seismic petrophysics

Well log data are used for a variety of purposes in seismic reservoir characterization workflows. Well log data are not only used in petrophysical interpretation and rock physics modelling routinely, but they are also used for:

- Wavelet estimation
- Low frequency model building
- Seismic velocity calibration
- Time-to-depth conversion
- Hard data in geostatistical modelling and inversion.

Good quality well logs data are essential for high-quality seismic reservoir characterization. Therefore we require that the logs:

- Are consistent inter- and intra-well
- Cover the entire vertical interval of interest
- Cover reservoir and non-reservoir rocks
- Represent the true, undisturbed rock properties

Unfortunately there are often significant problems in integrating the well data with the seismic data. Often the well logs data do not satisfy these criteria for various reasons:

- Different tool measurements
- Different borehole environments
- Poor quality logging conditions
- Invasion of borehole fluids into the formations
- Alteration of the formation properties due to the presence of the borehole and/or borehole fluids
- Missing data.

It is common in many companies to carry out petrophysical evaluation of logs, the generation of a petro-elastic model and the synthetic to seismic well tie, separately prior to integration, and typically to focus on a production zone of interest and try to edit, normalize and interpret the logs, creating a model that honours all available data in the zones of interest. Naturally this does not help to reduce the uncertainty in any of the individual processes nor to increase consistency across the data. Ideally the petrophysics, rock physics and well tie should be an integrated process to ensure consistency between the data and to reduce uncertainty; moreover, special attention should be given to non-reservoir formation, because low logging quality may occur more often on shale.

The main issues with measured well logs in our case study were: density quality at a single well, because of borehole rugosities, and environmental corrections for multi well consistency. Multi regression such as expression (1) or using the volumetric model synthesizing density expressed as eq. (2) is a good choice for replacing the poor quality data and to restore the true density values (Fig. 3).

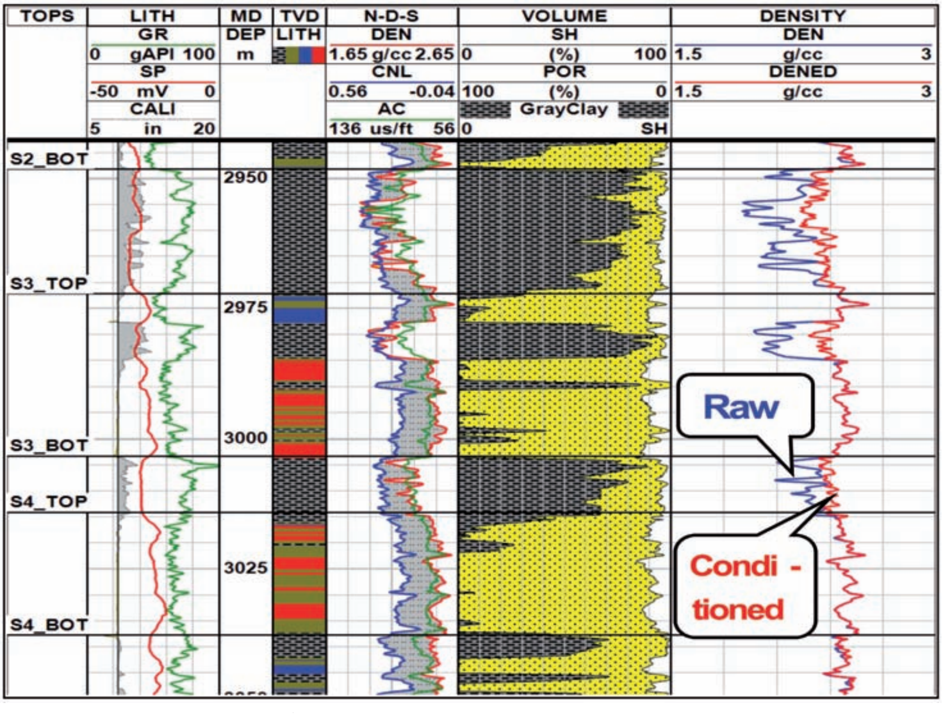

Fig. 3. Density log conditioning: the blue curve in the track named Density is measured logs, the red curve is conditioned density using the volumetric model synthetic method.

$$f_{\widehat{\rho_b}} = a\log_1 + b\log_2 + \ldots + n\log_x \ , \tag{1}$$

$$\rho_b = \rho_{m1}V_{m1} + \rho_{m2}V_{m2} + \ldots + \rho_{DCL}V_{DCL} + \rho_{bw}\phi_{bw} + \rho_w\phi_w + \rho_{HC}\phi_{HC} \ . \tag{2}$$

The geologic changes observed in the wells justify the use of the compaction-trend controlled "Big histogram method" (Shier, 2004) to ensure the multi-well consistency of the wells used in the seismic inversion (Fig. 4). This method first removes the compaction trends on the logs, and then creates the composite histogram cumulative probability distribution on all wells in the correlated interval. This yields an envelope into which the means of the individual wells must fit with a typical well based on a statistical "Normal Distribution" rule. If the envelope of an individual well does not match with a typical well, the data are adjusted on mean or standard deviations until they are similar.

The well tie with the real seismic full stack was improved in terms of waveform and amplitude (Fig. 5 left), resulting in rather stable multi well wavelets (Fig. 5 right). Moreover, the "Bull's eye" phenomenon observed on the low-frequency model without log conditioning was removed (Fig. 6).

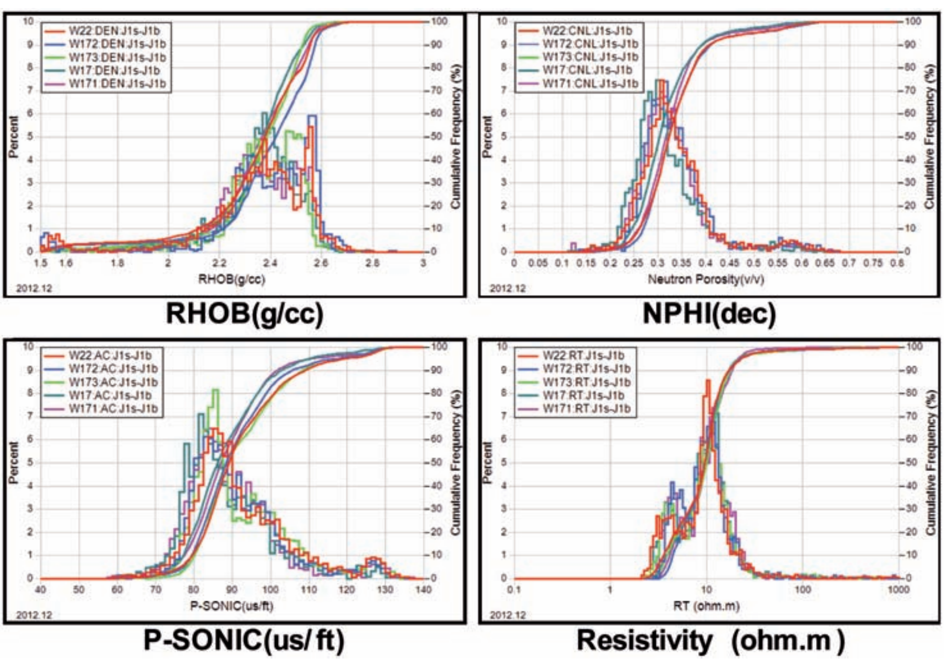

Fig. 4. "Big histogram method" multi well normalization on logs used in the petrophysical model.

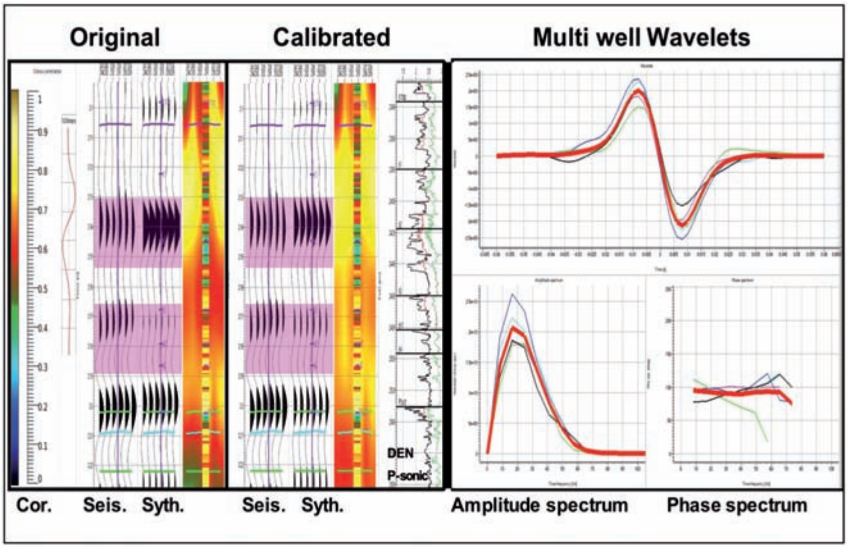

Fig. 5. Conditioning work to improve well tie on a single well and to stabilize wavelets on multi wells. The synthetic seismic amplitude using conditioned logs in the "Calibrated" pad better matches real seismic compared to synthetic seismic using raw logs in the "Original" pad. The wavelet from five wells is similar in amplitude and phase.

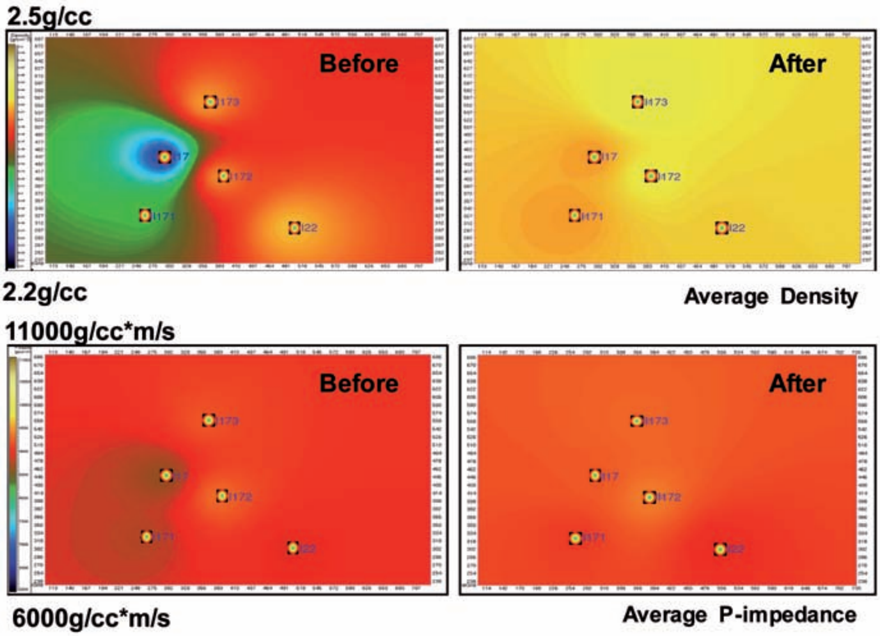

Fig. 6. Well log normalization improved the low frequency model used in seismic inversion; average density and P-impedance were extracted on the low-frequency model interpolated from well logs during the inversion time window; "Before" and "After" average value map trends were plotted for comparison purposes.

Rock physics model

Rock physics models have the ability to correct poor quality invasion or dispersion in wells, and generate synthetic density, compressive and shear data, and a rock physics interpretation chart, necessary for forward modelling and inversion.

The methodology applied was to construct a rock physics model that was consistent with the petrophysical analysis and the elastic properties of the rocks. In this study, the Grain-Supported Method which considers sand as grains and shale as the interstitial media based on Marion's grain support to clay support sediment theory (Marion, 1990) was used to model the elastic logs. Based on the petrophysical results, this model matches the fan delta rough sand's physical model and is more accurate for predicting elastic properties than the Xu & White model (Xu and White, 1995). In the Grain-Supported model method, mineral and fluid phases are sequentially introduced into other media using the differential-effective medium (DEM) (Norris, 1985) theory. DEM calculations utilize the Kuster-Toksöz (Kuster and Toksöz, 1974) equations to give incremental changes in bulk and shear moduli as small amounts of the inclusion phase are added. The overall rock model is one of sand media with pores of clay. The clay pores include pores of fluid. The sand media also contain fluid filled pores. Fig. 7 illustrates the distribution of components (but not the physical relationships among the constituents) in a real rock.

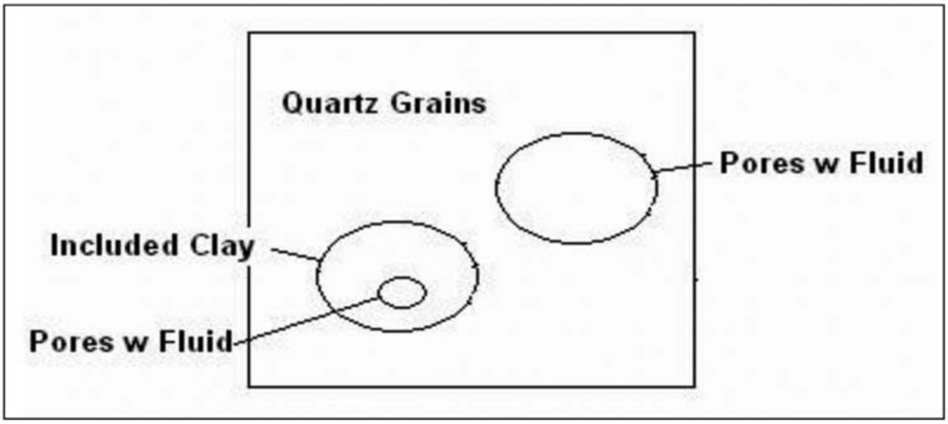

Fig. 7. The distribution of components in the Grain supported model.

Calculation procedure:

a. Brine and gas properties in original reservoir pressure and temperature conditions were computed by the method from the 2008 fluid consortium. The brine and the gas were mixed together according to the saturations using the Brie equation (Brie et al., 1995).

b. The first phase to be introduced is clay with included fluid. Before it can be introduced in the quartz medium, the bulk and shear modulus of the clay with fluid must be estimated. This is also done using DEM to introduce fluid in a clay medium.

c. Once the bulk and shear moduli of the clay with fluid are determined, inclusions of clay are introduced into the sand medium. The clay fraction and mineral fraction are mixed as matrix. This gives the bulk modulus

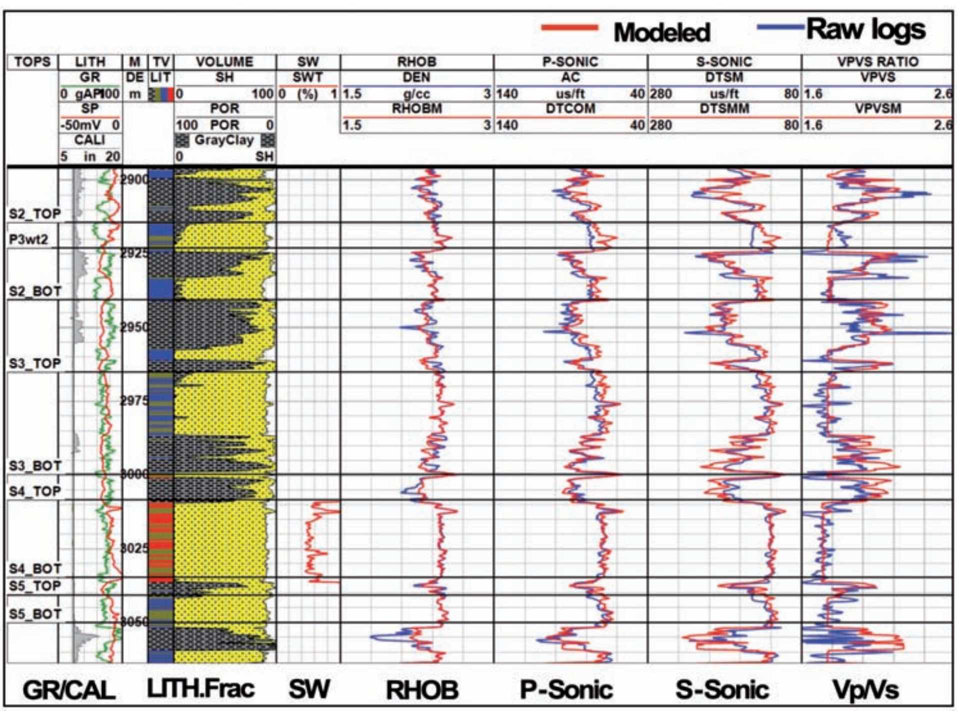

Fig. 8. Rock physics model prediction of elastic logs vs. measured logs: the mineral volumes from the petrophysical analysis are presented in the "VOLUME" track, the water saturation in the "Sw" track, the measured (blue) and modelled (red) logs are presented in the "RHOB" track for density, "P-SONIC" track for P- sonic, "S-SONIC" track for S-sonic", and "V_P/V_S Ratio" track for "VPVS", respectively.

and shear modulus of the elastic properties of the sand medium with inclusions of clay with fluid, but with no pores associated with sand.

d. The DEM approach is used a third time to introduce empty pores into the sand medium only to determine the empty frame bulk modulus and shear modulus, and clay with a fluid medium was used as an inclusion in this step.

e. Gassmann's equations (Gassmann, 1951) were applied to introduce the fluids into to the empty pores to determine the bulk modulus and shear modulus of fluid-saturated rock.

The details of the modelling results and the comparison with the measured data for the target well section in this case study are presented in Fig. 8. The highly detailed match between the modelled and raw logs proved the rock physics model's high predictability.

Once a predictive rock physics model is created, the fluid substitution (Smith et al., 2003) work can be done to calibrate the mud invasion effect on density and sonic logs. It is also very helpful for understanding the relationship between the petrophysical and the elastic rock properties. The rock physics interpretation chart (Xingang and Dehua, 2009) provides a framework for the interpretation of seismic inversion elastic property volumes (Fig. 9). This can indicate the feasibility for seismic inversion to be used to predict the reservoir properties away from the well locations. The chart overlapped with measured logs shows that the P-impedance can separate shale and sandstone on the whole and there was little overlay for different lithology. There was also a small window between the oil and brine sand. Fluid lithology can be distinguished on the whole at logging scale.

AVA gather forward model

Well angle gather forward modelling based on curves derived from the rock physics model and extracted wavelets from seismic can give us information about lithology, fluid sensitivity to seismic amplitude and reflectivity. This can help to conclude how much AVO effect there is within. A typical well was completed on the items shown in Table 1, and a Zoeppritz equation was used as the AVA gather synthetic method in the study.

The maximum positive amplitude and maximum positive reflectivity were extracted on the top of the reservoir, and the time window was about five micro seconds up and below the reservoir top. An example of a forward modelling angle gather for a typical well was drawn in the left panel of Fig. 10 and the extracted AVA curves in the right panel.

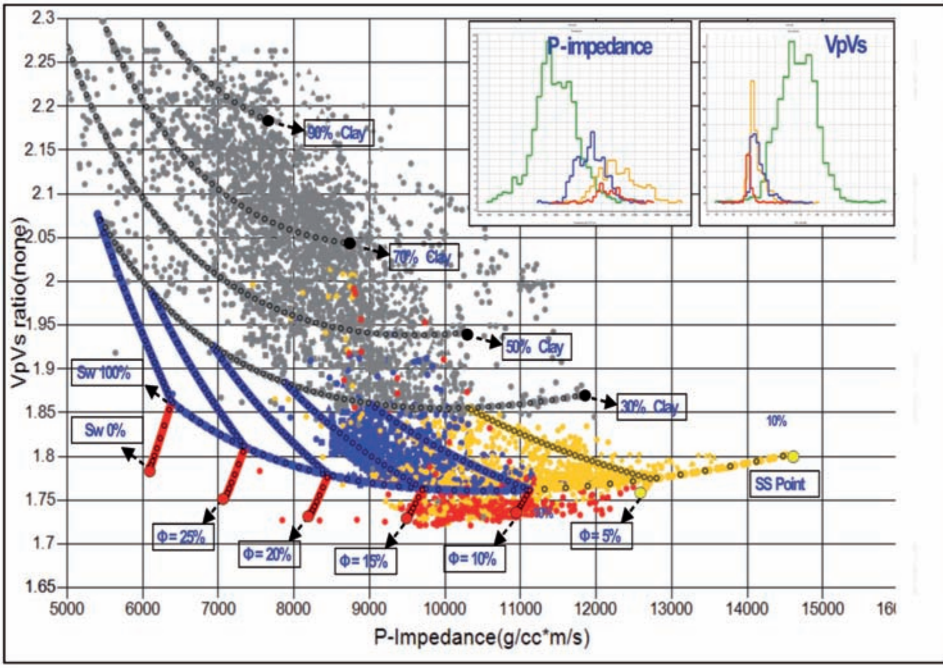

Fig. 9. Fluid and lithology sensitivity windows on the rock physics interpretation chart. P-impedance vs. V_P/V_S cross plot, with the scatter points from two wells with dipole sonic logs, the colours stand for four different lithologies from wells.

The AVA curves indicate that there is a class-AVO response type on oil top-, and porosity can induce large intercept changes; the shale content induced AVA changes that were less significant than porosity; fluid-induced AVA changes were small compared to porosity. But those AVO changes may not all be due to the change in elastic parameters, as the tuning effect has a great impact on the AVO response of these thin beds. Reflectivity (impedance) is the most reliable parameter for quantitative seismic interpretation.

Oil Water Contact forward model

The ability of seismic inversion elastic parameters to predicting lithology, porosity and fluid on a seismic scale can be modelled by the Oil Water Contact Model workflow (Fig. 11).

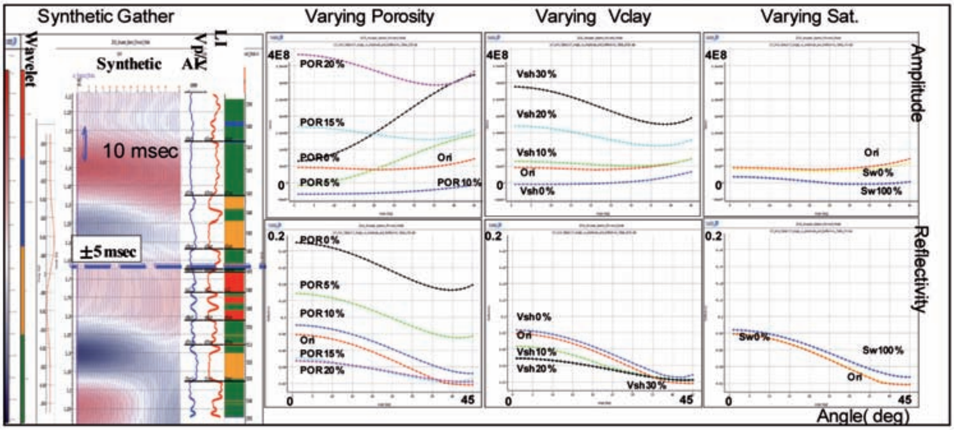

Fig. 10. The modelled angle gather's amplitude and reflectivity varied with reservoir porosity, clay content and water saturation. The angle interval is 0 - 45 degrees, with an increment of one degree. The wavelet used was extracted from seismic data. Each model used the properties in situ as shown in Table 1, except for the one variable that is changed for the reservoir.

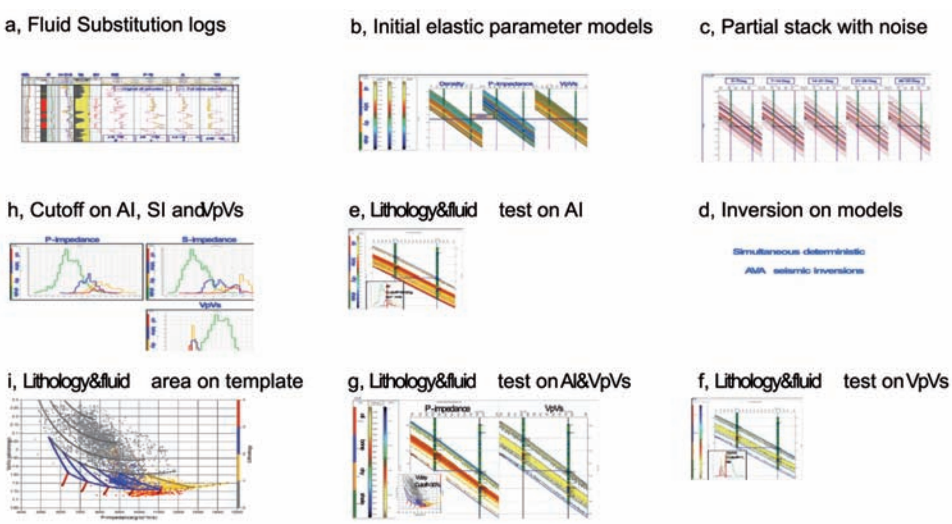

Fig. 11. Oil Water Contact Model workflow. Simultaneous AVO seismic inversions was computed using the input from five modelled partial-angle stacks from fluid substitution logs, lithology and a fluid sensitivity test carried out on a single cut-off and rock physics interpretation chart at seismic resolution scale.

Table 1. Zoeppritz equation well angle gather modelling list.

Angles models to create for 0 to 45 degrees	Variables to evaluate
Existing well conditions - in situ properties	Current thickness, porosity and saturation
Reservoir porosity - only vary porosity	0%, 5%, 10%, 15%, 20% p.u.
Reservoir Clay Mineral - vary clay volume	Increase or decrease reservoir clay mineral to 0%, 10%, 20%, 30%.
Reservoir water saturation - only vary saturation	Reservoir saturation to 100% brine or 100% oil

Calculation procedure

a. Oil/water fluid substitution based on a rock physics model produces original oil saturated and full brine saturated elastic curves.

b. Interpolate original oil saturated and full brine saturated elastic curves to obtain initial P-impedance, V_P/V_S and density oil water contact (OWC) model.

c. The partial angle stacks based on the OWC Model and wavelet from seismic were created using a Zoeppritz equation; maximum incidence angle and the number of partial angle stacks should match the real data that will be used in real inversion. 10% random noise (20 db) was added to the synthetics for this case study which was akin to the signal-to-noise ratio of the real seismic data.

d. Simultaneous AVO seismic inversion was computed as the input for five modelled partial-angle stacks (0-7, 7-14, 14-21, 21-28, 28-35 degrees). This required wavelets and the merge frequency of the low frequency model matching the parameters used in the real inversion. The algorithm incorporates all the input data with exact solutions to the Zoeppritz equations to determine P-Impedance, S-Impedance and density simultaneously at each grid point in time and 2D space (Pendrel et al., 2000). The far angle stack was not at a sufficiently high angle to determine density uniquely in this case study.

e. The interpretation can be made based on the histogram distribution of P-impedance only, and the sand is only a little overlapped with shale. The result is that thick sands are discerned clearly, but most of the thin sands overlap with shale. This means a single cut-off value cannot extract the sand effectively, let alone the oil sand.

f. The interpretation can be made based on the histogram distribution of V_P/V_S only, the sand is almost separated from other lithology on the histogram. It is therefore better than P-impedance only for interpretation, but there was also some thin shale overlap with sands, and no fluid windows were detected either.

g. The interpretation can be made based on P-impedance versus V_P/V_S, a classic cross plot among the rock-physics interpretation templates, and it was better than a single discriminator. Sands were more continuous. The discrimination of shales and sands is improved, however thin shales overlap with thick sand formation even on the P-impedance versus V_P/V_S cross-plot.

It can be concluded that:

- P-impedance and V_P/V_S ratio are effective elastic properties for seismic lithology detection except for thin shales because of resolution issues.

- The hydrocarbon response is much lower compared to noise.

- The cross plot of P-impedance vs. the V_P/V_S ratio rock physics interpretation chart is the most accurate tool for 3D visualization and lithology interpretation in this case study.

Wedge model

A simple wedge model can tell us where the most serious wavelet tuning effect occurred, and also we can deduce the lower limit of deterministic inversion resolution.

This wedge model consisted of three layers (Fig. 12), and each layer was filled with detailed acoustic impedance parameters according to a real reservoir situation. Above and below the wedge, the shales parameters were used (yellow and orange in Fig. 12). The wedge was filled with sandstone parameters (green in Fig. 12). We can model a synthetic seismic section through the convolution of a wavelet extracted from the real data with the wedge model.

The maximum seismic amplitude on the sandstone bottom can be extracted as a tuning curve. It shows that the maximum tuning effect occurred when the reservoir time thickness is about 15 milliseconds, which means that the resolution of deterministic inversion is 14 meters (the velocity is about 3770 meters per second here). As most of the sands are thinner than 14 meters,and the quality of pre-stack seismic was not good enough, the maximum incidence was 24 degrees,and highly detailed geostatistical post stack inversion was used to detect sand bodies.

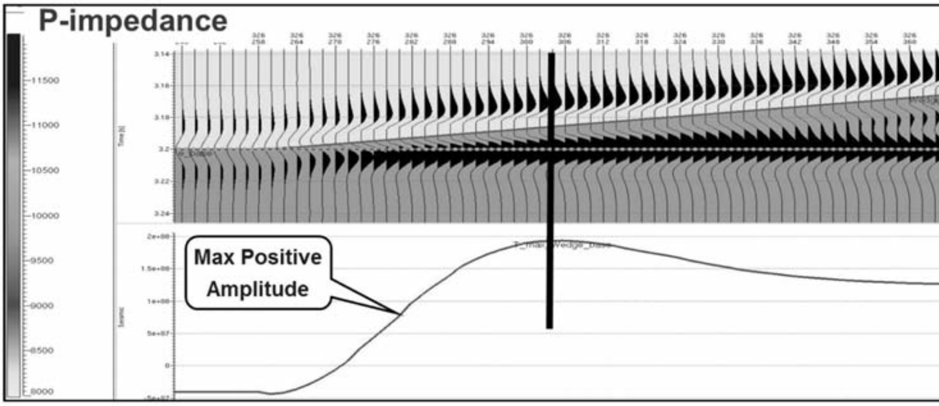

Fig. 12. Tuning curves from the wedge model: the black vertical bar marks the most serious tuning effect state, and also defines the limited resolution of deterministic seismic inversion.

Geostatistical inversion

The geostatistical inversion can provide high-resolution unbiased estimates of sandstone bodies. The algorithm used was not a model-based P-impedance inversion which incorporated all the features of deterministic inversion. Similar to all geostatistical simulation techniques, any number of images or realizations can be produced in terms of lithology distributions and elastic properties. This algorithm does this by using Bayesian inference to compute sets of probability density functions representing elastic properties and lithology facies. These are then sampled by a Markov Chain, Monte Carlo (MCMC) technique. As in the deterministic inversion, the input data are the stratigraphic framework, noisy 3D seismic full stack and the wavelet. The low frequency model is not necessary here and the input well logs can be used as explicit constraint or held blind for quality control. The geostatistical model comprises variograms for the lithology types and separate variograms for acoustic impedance property within each lithology type, in our cases the lithologies are sand and shale. In addition, the estimate of the proportion of each lithology type and seismic signal to noise ratio must be specified. These key parameters of the geostatistical model are obtained after strict geostatistical inversion test workflow as designed in Table 2. A total of 20 joint realizations of lithology and acoustic impedance were generated.

Table 2. Designed values for each property that are used in geostatistical inversion test and adopted geostatistical model parameters final.

Property	Minimum	Maximum	Steps	Adopted	Test times
Shale continuous properties					
Lateral variogram range (m)	400	2400	200	1400	6
Vertical variogram range (ms)	2	10	2	8	4
Sand continuous properties					
Lateral variogram range (m)	400	2400	200	1400	6
Vertical variogram range (ms)	4	16	2	12	6
Shale discrete indicator					
Lateral variogram range (m)	1000	3000	400	2200	5
Vertical variogram range (ms)	4	16	2	12	6
Sand discrete indicator					
Lateral variogram range (m)	1000	3000	400	2200	5
Vertical variogram range (ms)	8	20	3	16	4
Lithofacies Proportion					
sand to shale (%)	50	90	5	65	8
Seismic					
Signal to noise (db)	8	16	1	12	8

Two quality control methods are mainly used in this case study. One compares the P-impedance curve extracted at the borehole position by full stack deterministic inversion with the P-impedance of the well logs in the seismic frequency domain (Fig. 13). This can show how much predictability seismic has and whether the geostatistical inversion parameters such as signal-to-noise ratio and wavelet, used in the deterministic inversion, are reasonable. The other method involves checking the blind well's predictability during the test of the geostatistical inversion parameters. The most rigorous test should use one well to predict the others. We use one well to predict the lithology of four other well with about a 90% success rate (Fig. 14).

An arbitrary line section across one well was drawn through the project, and full angle seismic stack with the deterministic and geostatistical inversion acoustic impedance result were shown for comparing purpose (Fig. 15). The geostatistical inversion result used here is the mean of 20 realizations rather than a single realization in order to decrease the uncertainty on acoustic impedance. Clearly, the geostatistical result contains more detail. A close-up at the W173 well location can give us more details on resolution (Fig. 16). It is observed that the deterministic inversion resolved bed thicknesses of around 15 meters at best

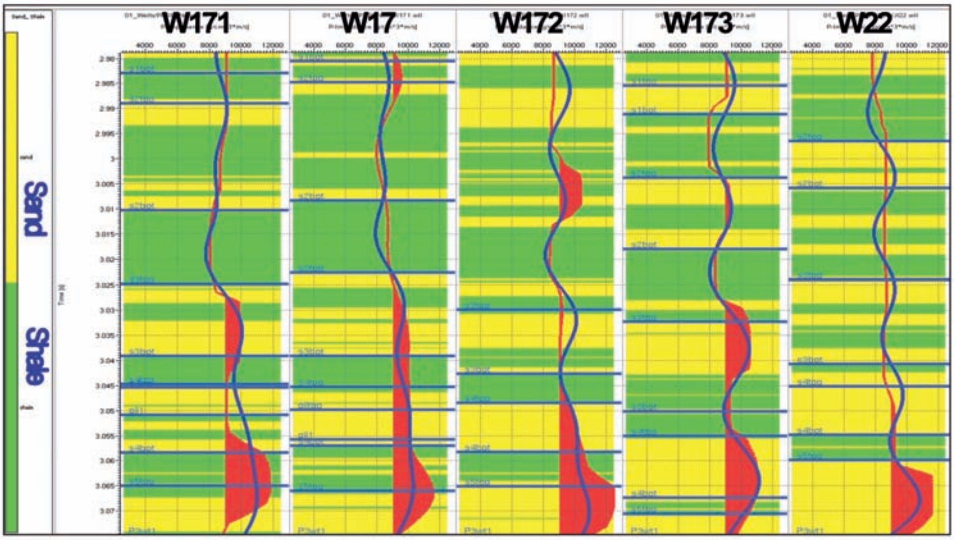

Fig. 13. P-impedance extracted from deterministic inversion in red compared with the well logs in the seismic frequency domain in blue.

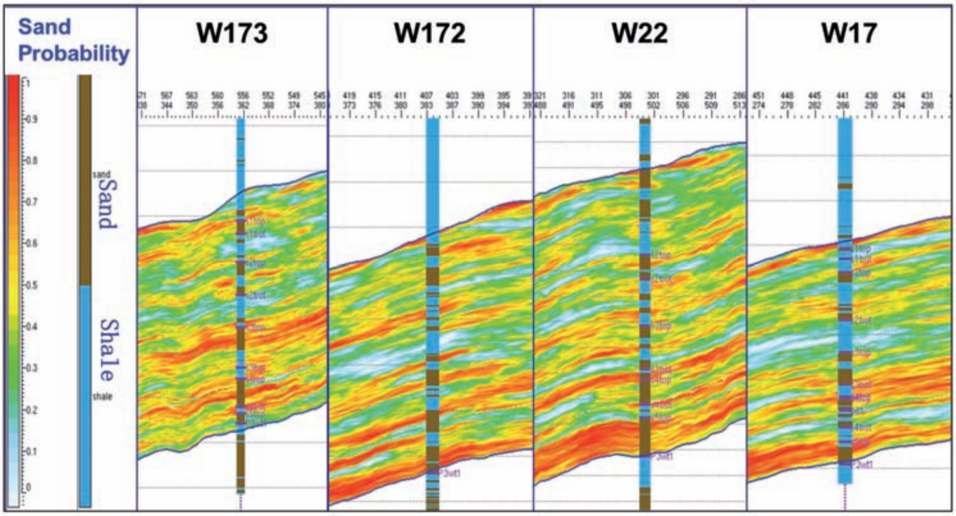

Fig. 14. Blind well test when only W171 is used in the geostatistical inversion.

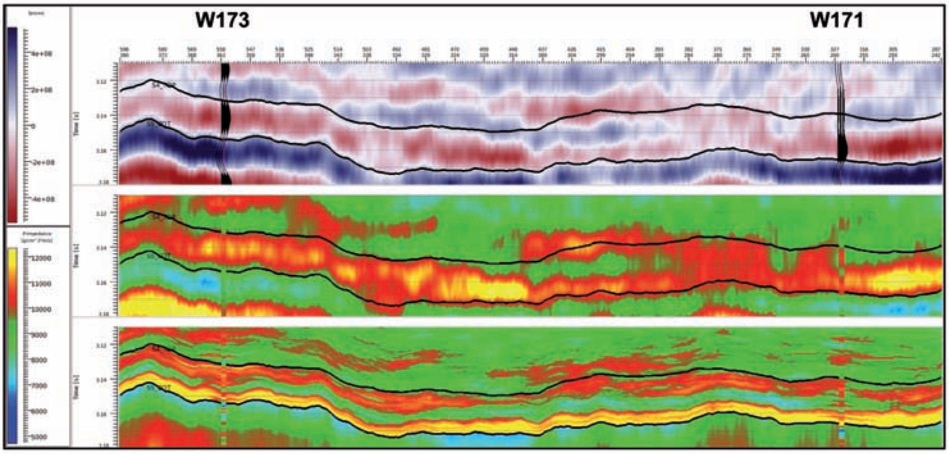

Fig. 15. Comparing full stack seismic and inverted data over the study area. The top panel shows the full stack seismic. The centre panel shows the acoustic impedance from the deterministic inversion. The lower panel shows the mean of acoustic impedance from a set of realizations of a geostatistical inversion. Note the large increase in detail in the lower panel. Wells W171 on the right and W173 on the left show the high-cut filtered P-Impedance logs displayed on top of the inversions.

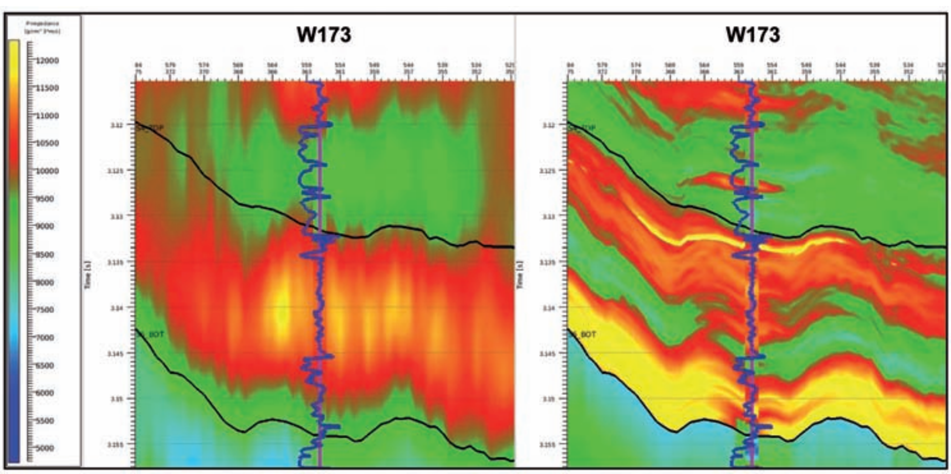

Fig. 16. The left panel shows the deterministic acoustic impedance while the right panel shows the mean from a set of realizations of geostatistical acoustic impedance. The well track on both panels shows smoothed log derived density display of acoustic impedance overlain with an effective porosity curve.

which was consistent with the conclusion that Wedge Model tell us, but the geostatistical inversion in general can resolve thicknesses between 4 to 14 meters despite the bandlimited nature of the seismic data. This improvement is linked to the fact that geostatistical inversion is only allowed to select acoustic impedance values from the probability density functions (PDFs) for each lithology. Since there is little overlap of these PDFs in this case, there is less room for variation in the possible lithology configurations that will fit the seismic data. In addition, even the large variation in lateral and vertical variogram range that has been selected for the inversion does not result in a significant blurring of the image.

Interpretation of inversion result

Geostatistical inversion can give two volumes of lithology probability for each realization, one for sand and one for shale. The idea for interpretation is to use the sand probability to identify sandstone bodies from the high-resolution geostatistical inversions. This is achieved by combining 20 sand lithology realizations to give a sand lithology probability model to reduce the uncertainty at first, and then using a cut-off value of sand probability on a cross-section viewer. Fig. 17 shows that there are mainly two sand bodies separated by a thin

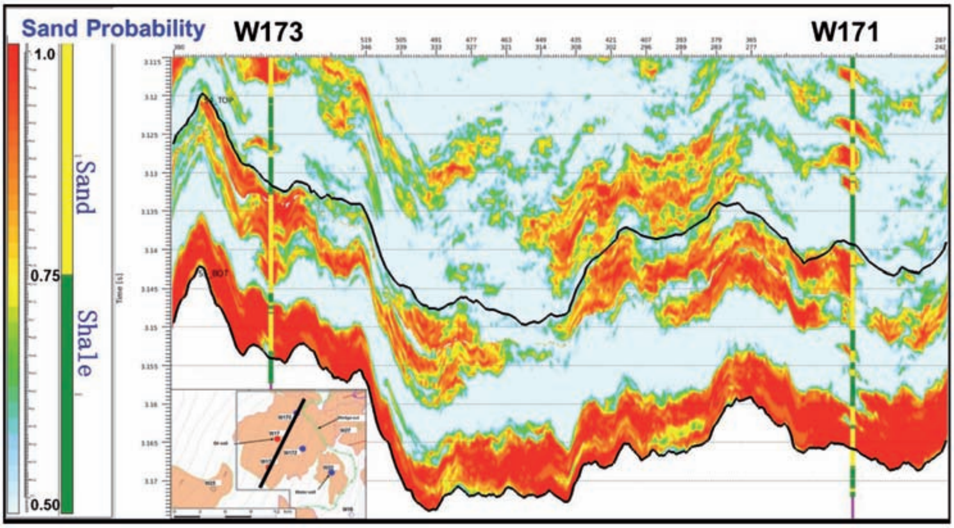

Fig. 17. Arbitrate line of highly detailed sand probability section view across wells W173 and W171, the sand probability is plotted from the cut-off value 0.5 for sand lithology interpretation purpose. Two black seismic horizons defined the main inversion windows which including S4 and S5 sand group, S4 sand group is on the top and S5 sand group located in the bottom of the inversion window.

continuous shale in the main inversion window which comprised two seismic horizons in black: S4 and S5 sand interpreted on the bases of the well logs. S4 sand is slightly shallower and would be porous sand which produced oil on W171, but water on W173. S5 sand is tight and has no liquid producing capability on all wells until now, including W171 and W173 of course. Sand probability inversion result tells us S5 sand on the bottom is steady distributed and transversely continued in the space, but S4 sand is much different in terms of thickness and lateral continuity. Many internal micro structure features can be observed inside S4 sand body. It is likely that S4 is comprised of multi sand-gravel fans which came from different period and directions.

Fig. 18 shows a cumulative sand thickness map display for porous sand group S4 overlapped on structure. Areas with sand probability above 0.5 were accumulated in map viewers to enable interpretation from the geobodies concept, and it was found that wells W17 and W171 were located in a single geobody for the main oil sand group S4, which gives the real reasons from a geology viewpoint as to why water is produced from the higher spot while oil is produced from the lower position in this case study. This is because the variation in lithology controlled the hydrocarbon distribution instead of structure.

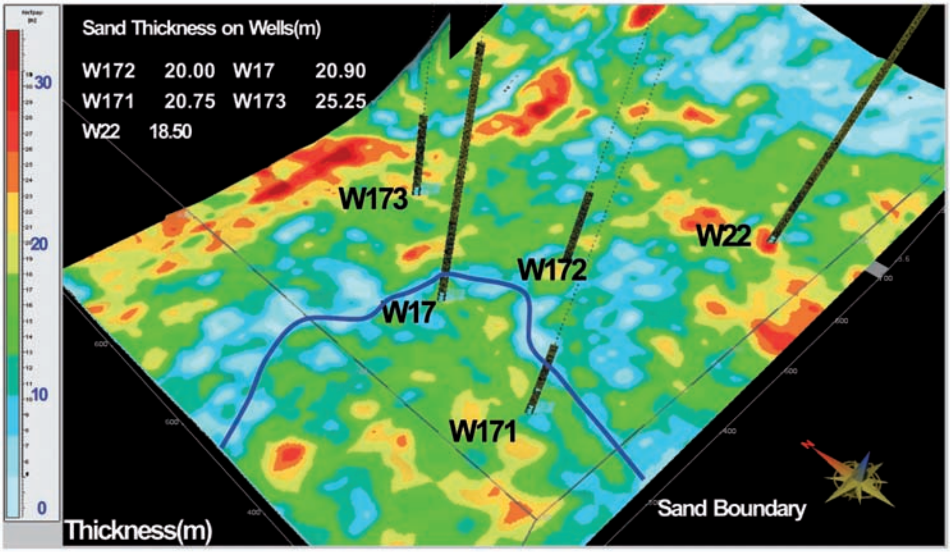

Fig. 18. Cumulative thickness map of the main oil sand group overlapped on structure. The thickness is achieved by the cut-off value of sand probability above 0.5 and the reservoir's average velocity from wells. The oil sand boundary is in solid blue.

CONCLUSION

Integrating rock physics with petrophysics, seismic forward modelling and inversion technology promotes consistency from the petrophysical interpretation right the way through to the seismic reservoir characterization. A seismic petrophysics study can improve well tie quality and remove the "bull's eye" effect on the low frequency model used in seismic inversion, providing the necessary dataset for a rock physics study. Rock physics focuses on establishing relationships between rock properties and observed seismic response. The scope can extend from the surface to the total depth, not just the reservoir zone. The goal is not only to synthesize logs where sonic and density curves are not available, but also to construct a model where it is possible to merge data and knowledge from different disciplines into one common scale. Rock physics-based seismic forward modelling is essential for a complete understanding and utilization of seismic data, and it is really helpful and critical to develop the right workflow to describe the spatial distribution of sandstone reservoirs in this case study. Highly detailed geostatistical inversion results show the final reservoir spatial distribution, including the sandstone discontinuity and horizontal thickness trend, providing the necessary information for reservoir engineers, geologists, and geophysicists to intelligently judge the risks and opportunities involved.

The benefits of an integrated workflow can be summarized in the three points below:

- Reduce uncertainty

  An integrated process ensures all the expensive measured data will be used together and when the analytical environment (processes, parameters, models) is consistent, it is more likely that this integrated approach will minimize the uncertainty, enhance the understanding of its positive function and illustrate its negative risks.

- More accurate and trustworthy results

  When all the data is in agreement, there is greater confidence in the results. Integration promotes this agreement. Tight integration leads to increased credibility and greater acceptance of decisions based on these results. Integration provides a thorough understanding of the relationship between reservoir properties and seismic data, greatly enhancing the reliability of interpretations. Well-to-seismic ties are improved. Models are more reliable vertically, laterally and on the trend map.

- Increase efficiency

Integration leads to faster project turnaround and more timely delivery of useful results. Every step in reservoir characterization and beyond is made more efficient. Petrophysics and rock physics are the foundation of reservoir evaluation, seismic forward modelling and inversion. By integrating these disciplines, efficiency is gained.

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